IURC STAFF WHITE PAPER
Energy Policy Act of 2005:
Suggested Standards for State Consideration

April 2006

Introduction

The Energy Policy Act of 2005 (EPAct05) is the first comprehensive national energy legislation in 13 years. This paper focuses on the changes to Public Utility Regulatory Policy Act (PURPA) by the EPAct05 in the form of new federal suggested standards and attempts to summarize the actions needed by the IURC to meet the related consideration requirements.

Enacted in 1978, PURPA promoted change in public utility regulatory policies at the state and federal levels. PURPA is intended to encourage (1) conservation of energy, (2) optimization of electric utility facility and resource efficiencies, and (3) equitable rates to electric consumers. The pertinent section of PURPA sets out regulatory standards for state commissions to consider and then determine whether they are appropriate to implement. Prior to 2005 PURPA established federal suggested standards for;
(1) Cost of service,
(2) Declining block rates,
(3) Time-of-day rates,
(4) Seasonal rates,
(5) Interruptible rates,
(6) Load management techniques,
(7) Integrated resource planning,
(8) Investments in conservation and demand management,
(9) Energy efficiency investments in power generation and supply, and
(10) Consideration of the effects of wholesale power purchases on utility cost of capital; effects of leveraged capital structures on the reliability of wholesale power sellers; and assurance of adequate fuel supplies.
The 2005 amendments add five new PURPA federal suggested standards to address current conservation and efficiency needs dealing with net metering, smart metering, interconnection, fuel source diversity, and fossil fuel plant efficiency.

States must consider and determine whether each of the five new PURPA standards is appropriate for their jurisdiction. Though states must consider the standards, nothing prohibits a state commission from determining that it is not appropriate to implement a standard pursuant to its authority under otherwise applicable state law. The consideration is to be made after public notice and a hearing. The determination must be in writing, based upon evidence presented, and available to the public. Prior state actions can substitute for the consideration and determination requirement, if before August 8, 2005;
the state has implemented the standard (or a comparable standard) for the utility;
the state commission has conducted a proceeding to consider implementation of the standard (or a comparable standard); or
the state legislature has voted on the implementation of the standard (or a comparable standard).
The interconnection and net metering suggested standards appear to be substitutable as a result of recent Indiana rulemakings.

PURPA applies to each electric utility in any calendar year, and to each proceeding relating to each electric utility in such year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year. The IURC consideration of the federal suggested standards would apply to each electric utility for which it has ratemaking authority. A review of the Commissions 2004 Annual Report would identify, based on the above criteria, the five investor-owned electric utilities, the Cities of Anderson, Auburn, Mishawaka, and Richmond, and the Harrison and Northeastern REMCs as applicable Indiana electric utilities.

A state's failure to comply with the standard setting requirements triggers PURPA Section 112(c) which requires that the consideration and determination be undertaken in the first rate case proceeding commencing after the deadline.

The following sections explore each of the federal suggested standards added to PURPA under EPAct05 in turn and include an overview of the standard, the related environment in Indiana today, the status of Indiana in considering the suggested standard, and a suggestion of actions.

Suggested Standards for Consideration

Net Metering

Amendments to PURPA; Sec. 1251; amending 16 USC 2621(d) by adding (11) – Net Metering

"Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period."[1]

Introduction

Net metering service as defined means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period. Net metering serves as an incentive to the installation of eligible facilities by consumers. Without net metering a consumer with an installed generator could "stop" the metering when it was generating more electricity than it was consuming, while under net metering the same consumer can "run the meter backward" during such conditions and essentially create a savings bank of any excess energy it generates. This incentive

[1] In the context of PURPA, the IURC, with respect to each electric utility for which it has rate making authority, undertakes the consideration of the suggested standards.

provides an opportunity for an additional offset to the costs the specific consumer sees when they elect to become a partial generator of their own electrical needs.

The rules under which net metering is provided should strike a balance between providing an incentive to a specific participating consumer, protecting the legitimate financial and safety interests of the affected utility, and not creating unwarranted subsidies born by the non-participating consumers. The factors which define a net metering program are primarily any generator type and size limitations, class of customers allowed to participate, details of the billing process, interconnection costs and operation standards, and definition of the liabilities born by both the utility and the participating customer.

The vast majority of states have created rules which allow for net metering. The terms and conditions for the specific state programs vary widely and are generally reflective of the specific electricity regulatory environment of each state.

Indiana Today

Indiana investor-owned utilities are required to offer net metering in accordance with 170 IAC 4-4.2, "Net Metering Rule". The net metering rule was approved in October 2004 and provides an opportunity for residential customers and K-12 schools with solar, wind, or hydro-electric facilities with a nameplate capacity of 10 kW or less. A standard simplified interconnection would add no costs for utility analysis or inspections to the customer, any earned energy credits are carried forward indefinitely, and requires the customer to carry a nominal amount of insurance, $100,000, for related liability.

Status vs. EPAct05 Requirement

The EPAct05 suggested standard calls for net metering to be available to any electric utility customer. The recently completed Indiana rule making considered the full range of variables and determined through the process prescribed by IC 4-22-2 the applicable terms and conditions under which Indiana electric utilities must offer net metering to their customers.

Future Action Plan

None required; the recently completed rulemaking satisfies the EPAct05 requirement of considering this suggested standard.

Fuel Sources

Amendments to PURPA; Sec. 1251; amending 16 USC 2621(d) by adding (12) – Fuel Sources

"Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies."[1]

Introduction

Constructing power portfolios that limit the dependence on a single fuel source is a worthwhile goal. Diversified power portfolios mitigate exposure to both operational and financial risks associated with over-reliance on a single fuel source. Fuel diversity can produce a variety of benefits: reduction of price volatility, environmental benefits, and improved system reliability; however, the benefits must justify the costs.

Utilities' power portfolios are built by performing a delicate balancing act among environmental, social, political, and economic concerns. These portfolios are capital intensive and long-lived. These two factors inherently make power portfolio investments risky, and utilities will seek to minimize this risk. Rules and laws that allow utilities to minimize the risk in building or extending the life of power plants may incent utilities to consistently prefer generators using specific fuel types. As such, it is important for federal, state, and local authorities to give clear and consistent guidance in rules and laws that affect how utilities develop their power portfolios.

Currently, many state regulatory bodies require utilities to file periodic long-term integrated resource plans ("IRPs") that identify how utilities will meet future consumer energy demand, while accounting for environmental, social, political, and economic concerns. The stated goal of many of these IRPs is to develop a plan that reliably meets expected future demand at the lowest reasonable cost. The most reliable, lowest reasonable cost IRPs do not necessarily entail the most diverse set of generator types and corresponding fuel types. However, some utilities have recently implemented diversified planning strategies that balance least-cost reliable service with social and environmental concerns. Within this context, fuel diversity is an available alternative to reduce operational and financial risks.

Indiana Today

Pursuant to 170 IAC 4-7- et al., Indiana electric utilities are required to file integrated resource plans ("IRPs") with the Commission biannually covering a forward period of twenty (20) years. As part of the requirements of 170 IAC 4-7-4, utilities are required to discuss "the goals and objectives of the plan", which are usually the development of plans that reliably meet customers' future needs at the lowest reasonable cost. In reaching this goal of the IRP, utilities must demonstrate that the plan: accounts for risks associated with potential environmental and other regulations; utilizes non-conventional renewable generating resources where practical; accounts for existing and proposed regulations, laws, practices, and policies; is a workable strategy that allows the utility to adapt to unexpected circumstances and preserves the plan's ability to achieve its intended purpose. [170 IAC 4-7-8 (5, 4, 9, 10)] In addition to these broad IRP requirements, descriptions of the utilities' electric power resources, including a fuel price forecast by generating unit, and significant environmental effects, are required by 170 IAC 4-7-6(a)(3,4).

The Indiana IRP rules noted above inherently require Indiana utilities to contemplate the effects of dependence on a single fuel source. By considering possible future environmental laws, federal and state energy policies, and swings in fuel prices, Indiana's utilities should develop resource plans that account for the risk of being adversely dependent on a single fuel source.

Following is a snapshot of Indiana generating utilities generating portfolios today.

				(MW)		Other	
Utilities	Coal	Nuclear	Nat Gas	Oil	Hydro	Renewable	Total
PSI	5,163	0	1,378	236	45	0	6,822
I&M	3,190	2,093	0	0	11	0	5,294
NIPSCO	2,574	0	306	0	10	0	2,890
IPL	2,707	0	461	84	0	0	3,252
SIGECO	1,056	0	295	0	0	0	1,351
WVPA	156	0	148	0	0	19	323
IMPA	374	0	249	18	0	0	641
Hoosier	1,242	0	174	0	0	0	1,416
TOTAL	16,462	2,093	3,011	338	66	19	21,989
TOTAL %	74.9%	9.5%	13.7%	1.5%	0.3%	0.1%	100.0%

The table above shows coal to be a favored fuel for Indiana utilities. The amalgamation of many factors have led to coal's favored status: from the relative abundance of coal in the Illinois River basin, which parts of Indiana lie in, to the relative cost advantage of coal fired generation, to Indiana laws that are quite amiable to the use of coal as a source of electricity generation.

Status vs EPA05 Requirement
Indiana has not considered the suggested standard in the last three years.

Future Action Plan
Not later than 2 years after the enactment of the EPAct 2005, the IURC will have to commence the consideration of the suggested standard and not later than 3 years after EPAct 2005's enactment, the IURC will have to make the determination of whether the suggested standard has been fully considered. To begin such a consideration and determination, the Commission should construct and issue a data request to all generating electric utilities under its jurisdiction in an effort to determine the extent to which the specific utility has or plans to have a plan to minimize dependence on one fuel source and to the level at which the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies.

Fossil Fuel Generation Efficiency

Amendments to PURPA; Sec. 1251; amending 16 USC 2621(d) by adding (13) – Fossil Fuel Generation Efficiency
"Each electric utility shall develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation."[1]

Introduction

The Fossil Fuel Generation Efficiency suggested standard requires each electric utility to develop and implement a 10-year plan to increase the efficiency of its fossil fuel generation. The goal of increasing fossil fuel generation efficiency, or even more broadly any efficiency, is a worthy endeavor, but one that may prove difficult to implement and oversee. Increased generation efficiency reduces the consumption of fuel resources for a given amount of electricity generated and will also in turn limit the generation of associated by-products; namely air pollutants, waste heat, and solid waste. Increased efficiency will most likely also bring along an associated cost to implement which must be balanced against the gains.

The benefits of improved generation efficiency may accrue to both the utilities ratepayers and society as a whole. The ratepayers may see a reduced fuel cost, all else being equal, as a result of the reduction in fuel burnt for a given output and society as a whole will benefit from the reduced cost of fuel because of the reduced fuel demand and the reduction in waste and pollutant by-product generation.

The cost of improved generation efficiency will be borne by the utility shareholders or customers or both. The regulatory treatment of the capital and operating expenses of the fuel efficiency enhancement devices will determine the balance of this cost assignment.

The cost-benefit analysis for determining an economically efficient level of fossil fuel generation efficiency improvement is complicated by the difficulty in valuing the societal benefits. The cost is generally quantifiable while the societal benefits may be less so given their external nature. Furthermore, the tracking of efficiency gains will likely be subject to significant modeling assumptions because simultaneous state and federal supported activities may serve to reduce fossil fuel generation efficiency. Namely, the addition of pollution control equipment will generally lower overall plant efficiency because it consumes energy and therefore fuel. The fluid nature of pollution control targets would further complicate modeling assumptions. The effort and ability of the state to economically and accurately track fuel efficiency gains, especially in light of the potential for ratemaking incentives being afforded the utilities, should be an important consideration in the development of any related state standards. The not yet fully resolved delineation of what constitutes plant modifications sufficient to trigger New Source Review requirements should also be considered in any state mandated efficiency improvements as they may add substantial costs into any cost-benefit analysis.

Indiana Today

Indiana does not explicitly require its electric utilities to provide an ongoing program to increase the efficiency of its fossil fuel generation. The State does require that its utilities demonstrate that they have made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible as a component of their fuel adjustment charge proceedings. Additionally, Indiana utilities requesting a certificate of need are required to show that they have considered various efficient methods of providing electric service, including the refurbishment of existing facilities. The development of the wholesale markets, namely PJM and MISO, should also be expected to create a natural incentive for the utilities to improve efficiency and therefore the marketability of their generation fleet.

Status vs. EPAct05 Requirement
Indiana has not recently considered this suggested standard.

Future Action Plan
The Commission should construct and issue a data request to all generating electric utilities under its jurisdiction in an effort to determine the extent to which the specific utility has or plans to have a 10-year plan to increase the efficiency of its fossil fuel generation. The results of the data request will serve as the foundation to begin an open dialogue among all stakeholders in consideration of a fossil fuel generation efficiency standard. EPAct 2005 calls for consideration of this suggested standard to begin within 2 years (August 2007) and to be completed within 3 years (August 2008).

Smart Metering

Amendments to PURPA; SEC. 1252. Amending 16 U.S.C. 2621(d)) by adding:
(14) Time-based Metering and Communications.—
(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.[1]
(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others—

> (i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;
> (ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;
> (iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.

(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C)

<u>Introduction</u>

An important element of the 2005 Energy Policy Act is demand management, and smart metering is considered an efficient way to achieve demand response benefits. In theory, if enough consumers adjust their demand in response to time-based rate schedules, all of the stakeholders, including customers and utilities, will benefit. Therefore, the state commissions have one year to consider and two years to issue a decision regarding the smart metering standard.

Smart metering allows the consumer to manage their electricity consumption and cost through advanced metering and communication technologies. As real-time pricing reflect the variations in the utility's costs of generating and purchasing power at the wholesale level, time-based rate schedules will send appropriate price signals to the end consumers who then have the opportunity to adjust their demand accordingly. This reduction in demand will work to eliminate the need for older, less efficient and higher-cost generators to come-on line, thus, reducing the price of electricity to the end consumer.

The utilities, also, benefit from demand response programs. By including time-based rate options in their supply portfolios, the utilities have an additional alternative available to meet the growing demands for electricity. Furthermore, relying less on the older, less efficient generating facilities will decrease emissions from those facilities and have a positive impact on environment compliance.

Advanced metering technologies and communications will also provide new opportunities for utilities to offer additional services to the consumer. Smart metering: (1) can inform the customer on a variety of service related topics; (2) can generate an automated trouble ticket to the company, improving reliability and customer satisfaction; and (3) can enhance the utility's and customer's ability to manage power quality. These services will ultimately lead to a more efficient and reliable network.

In July 2005, smart metering and the use of critical peak pricing, credited as contributing factors, prompted consumers to reduce loads, thus avoiding a blackout in California. Notwithstanding the apparent success, California utilities hold various levels of acceptance, from territory-wide deployment to opposition of any deployment of advanced metering. Infrastructure costs are generally cited as the biggest obstacle to the development of smart metering programs.

Despite the potential benefits, the wide-spread implementation of smart metering is, at best, moderate. Although EPAct 2005 suggests time-based rate schedules for all customer classes, most current programs are intended for large commercial and industrial consumers. Primarily residential customers, but all customer classes will need assistance to develop an understanding on how time-based rates work and of the benefits of participating in such programs. Consumers are more likely to commit time and effort to reduce electricity costs, when the perceived benefit outweighs the effort.

In addition to the societal challenges, utilities also face regulatory obstacles going forward. Utilities have expressed concerns, fearful that investments may become stranded costs, about the recovery of costs associated with the necessary infrastructure to bring smart metering to the end consumer. The allocation of those costs between individual participants and all jurisdictional customers will be fervently debated. While ensuring the utilities of an opportunity for recovery of all reasonable program costs, successful programs are simple, and available options are customer class specific.

<u>Indiana Today</u>

While the Commission does not require utilities to offer smart metering options to all customer classes, Indiana utilities voluntarily offer a variety of demand management options. These offerings include time-of-use and real-time pricing and customer credits for interruptible service. Participation in these programs is generally limited to large commercial and industrial customers. Currently, residential customers have limited available options. As discussed in the 2005 Summer Reliability Reports, Indiana utilities have load management programs representing approximately 1,200 MWs of curtailable load, much of this control is in the form of interruptible rates and direct-load control.

<u>Status vs. EPAct05 Requirement</u>

Indiana has not recently considered this suggested standard.

<u>Future Action Plan</u>

The Commission must consider and issue a decision whether or not it is appropriate for utilities to provide and install time-based meters and communications devices for each of their customer classes. The IURC must begin consideration of these items by August 2006 and complete the review by August 2007. The Commission should issue a data request to all investor owned utilities seeking utility specific information relating to smart metering and time-based rate schedules. This information may lead to the scheduling of workshops to further the discussion of the smart metering standard.

Interconnection

Amendments to PURPA; Sec. 1254; amending 16 USC 2621(d) by adding (15) – Interconnection

"Each electric utility shall make available, upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection service shall be offered based upon the standards developed by the Institute of Electrical and Electronic Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services are offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such arrangements and procedures shall be just and reasonable, and not unduly discriminatory or preferential."[1]

Introduction

Interconnection service as defined means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. The process of interconnecting to a utility's electrical system is a detailed technical process that is inherently under the control of the specific utility. The specific utility has a statutory responsibility to ensure the safety and reliability of its electric system and is best informed on its characteristics. However, in-house control provides an opportunity for the utility to misuse the interconnection approval process as a means to discourage non-utility generators from connecting to its network. The incentive to discourage such connection may be to limit the connecting non-utility generator from competing with and possibly displacing utility generation in the provision of energy. Even absent any intended misuse, inconsistent interconnection procedures may create a patchwork of differing requirements that generator manufacturers must design their products to meet. Such inefficiencies drive cost into the generator manufacturing market and reduce the marketability of these products.

Indiana Today

Indiana investor-owned utilities are required to offer standard interconnection in accordance with 170 IAC 4-4.3, "Customer-generator Interconnection Standards rule" This rule, approved in November 2005, provides a multi-tiered approach to the interconnection process designed to allow the technologically simple interconnections to occur expeditiously with an increasingly stringent review of increasingly complex interconnections. The rule attempts to satisfy the needs of the utility to maintain safe and reliable distribution systems while providing a clear and efficient process to customers desiring to interconnect with them.

Status vs. EPAct05 Requirement
The EPAct05 suggested standard calls for the availability of interconnection to any electric utility customer in a just and reasonable, not unduly discriminatory or preferential manner. The recently completed Indiana rulemaking considered the full range of variables and determined through the process prescribed by IC 4-22-2 applicable terms and conditions under which Indiana electric utilities must offer interconnection of generation to their customers.

Future Action Plan
None required; the recently completed rulemaking satisfies the EPAct05 requirement of considering this suggested standard.

Summary

EPAct05 added five new federal suggested standards to PURPA and created a timeline for the states to consider each.

Schedule for Consideration and Determination of New PURPA Standards

	By Aug. 2006	By Aug. 2007	By Aug. 2008
Net metering		Begin Consideration	Make Determination
Smart metering	Begin Consideration	Make Determination	
Interconnection	Begin Consideration	Make Determination	
Fuel sources standard		Begin Consideration	Make Determination
Fossil fuel generation efficiency		Begin Consideration	Make Determination

It appears reasonable that recent Indiana rulemakings for net metering and standard interconnection serve to satisfy the consideration requirements for those two suggested standards. The consideration of the three remaining suggested standards should begin with an exploration of what the utilities are doing absent such standard.